METHODS FOR REDUCING METHANE EMISSIONS FROM NATURAL GAS SYSTEMS

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ABSTRACT
Natural gas systems throughout the world, from wellhead to the burner tip, emit methane from a variety of sources. This paper examines the main sources of gas loss, technologies and practices available for the effective reduction of methane emissions and to what extent the introduction of these practices can increase corporate revenue. All the technologies and practices mentioned in this paper are in widespread use in the United States.

1.0 INTRODUCTION

Although natural gas is seen as a relatively clean source of energy, methane emissions from natural gas systems in the United States account for approximately 1.8 percent of U.S. greenhouse gas (GHG) emissions. Because reduction of system losses leads directly to increased profits from additional gas sales, many natural gas companies in the U.S. have instituted practices that have led to reduction of their methane emissions. Although many of these practices are cost-effective, often paying back initial investment within the first year, significant emission reduction opportunities remain. Barriers to wider implementation include the availability of information, a lack of incentives to save gas, and reluctance to adopt new practices.

Since 1993, the USEPA Natural Gas STAR Program has worked with the natural gas industry to identify cost effective technologies and practices for reducing methane emissions. Gas STAR also develops technical documents and conducts workshops to increase understanding of these opportunities among its partners. This voluntary partnership has led to more widespread use of these technologies and practices, reduced emissions, and increased profits for the natural gas industry.

In an effort to facilitate additional methane emission reduction activities in the U.S. and internationally, this paper presents several technologies and practices that natural gas companies have implemented to reduce methane emissions and save money. It begins by discussing the major sources of methane emissions in the industry, and then gives brief descriptions of over a dozen technologies and practices to reduce those emissions, all in widespread use in the United States.

2.0 SOURCES

Overall, natural gas systems in the United States emitted 116.4 million metric tons of carbon dioxide equivalent (MMT CO_2 eq.) of methane in 2000. From the wellhead to the end user, the gas moves through hundreds of valves, compressors, pipes, gate stations and other equipment. Whenever the gas moves through valves and joints at high pressure, methane can escape to the atmosphere. Gas is also frequently vented to the atmosphere as a part of normal operations. Table 1 shows U.S. natural gas industry methane emissions in 1995 and 2000, some of the more significant sources of methane emissions, and selected technologies and practices applicable to each sector.

Table 1: U.S. Natural Gas Industry Methane Emissions, Sources and Remedies

Sector	1995 U.S. Emissions ($MMTCO_2$ eq.)	2000 U.S. Emissions ($MMTCO_2$ eq.)	Main Sources	Technologies & Practices
Production	31.0	26.2	Wellsite equipment, Pneumatic devices, and Dehydrators	Low-bleed pneumatics, Flash tank separators, Desiccant dehydrators, Plunger lifts, Vapor recovery units, Composite wrap
Processing	15.0	14.8	Compressors, Pneumatic devices, and Dehydrators	Low-bleed pneumatics, Flash tank separators, Desiccant dehydrators, DI&M[1] programs
Transmission	46.7	43.3	Compressors, Pneumatic devices, and Pipeline maintenance	Low-bleed pneumatics, Maintaining rod packing, Replacing compressor seals, Composite wrap, DI&M[1] programs
Distribution	33.0	32.0	Subsurface piping and Gate stations	Composite wrap, Pipeline pumpdown, and DI&M[1] programs

[1] DI&M = Directed Inspection and Maintenance

3.0 TECHNOLOGIES AND PRACTICES

Natural gas companies have discovered many ways to reduce the amount of methane emissions from their systems. The following section describes some of the more common cost-effective technologies and practices. Table 2 summarizes the volume and value of gas saved, the cost of implementation, and the expected payback period for the technologies and practices described in this paper.

Actual costs, methane savings, and payback will depend on site specific factors. This table is only intended to give the reader an understanding of the range of emissions reduction technologies and practices available and to suggest possible benefits associated with the activities. Many of the activities have other associated benefits relating to increased gas production, lowered operating costs, and improved safety.

Table 2: Emission Reduction Technologies and Practices

Action	Volume of Gas Saved (Mcm/yr)	Value of Gas Saved (US$/yr)	Cost of Implementation (US$)	Payback (months)
High-bleed pneumatics - replacement	1 - 6	150 - 600	150 - 250	5 - 12
High-bleed pneumatics - retrofit	6	690	500	9
High-bleed pneumatics - improved maintenance	1 - 7	135 - 780	0 - 350	0 - 5
Replace pneumatics with instrument air system	566	60,000	50,000/yr	<1
Reduce TEG circulation rates	4 - 372	390 - 39,400	0	0
Flash tank separator	7 - 201	710 - 21,295	5,000 - 14,000	5 - 17
Desiccant dehydrator	30	3,189	12,750	35
Plunger lift system	133 - 517	14,100 - 54,750	2,000 - 8,000	<12
Vapor recovery units	139 - 2,719	14,000 - 273,500	22,685 - 88,000+ 5,250 - 12,220/yr	3 - 41
Early rod packing replacement	24	2,595	400	0
Replace wet seals with dry seals	1,278	135,360	240,000	14
Composite wrap pipeline repairs	112	11,880	3,963	0
Pipeline pumpdown	5,664	600,000	75,000	2
DI&M at gas processing plants	956 - 2,719	101,250 - 288,000	53,000 - 128,000	6 - 12
DI&M at compressor stations	833	88,239	26,248	4
DI&M at gate stations	0 - 17	0 - 1,800	20 - 1,200	0 - 12

3.1 PNEUMATICS

Pneumatic devices powered by natural gas are used widely in the production, processing, and transmission sectors as liquid level controllers, pressure regulators, and valve controllers. As a part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere.

Many companies in all natural gas sectors have achieved significant savings and methane emissions reduction by replacing, retrofitting, or improving maintenance of the high-bleed pneumatic devices. Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Another option available at facilities with available electric power is to replace their natural gas-powered pneumatic control systems with compressed instrument air systems, eliminating 100% of emissions from pneumatics.

One company replaced 70 high-bleed pneumatic devices with low-bleed pneumatics and retrofitted another 330 high-bleed devices. This resulted in the reduction of 1,405 thousand cubic meters (Mcm) per year, worth US$148,800 at US$105 per Mcm. The costs of replacing and retrofitting the devices, including materials and labor, was US$118,500, resulting in a payback period of less than one year.

3.2 DEHYDRATORS

Many natural gas dehydrator systems in the production and processing sectors use triethylene glycol (TEG) to remove water from the natural gas stream in order to meet pipeline specifications. Often the glycol circulation rate is set much higher than it needs to be in order to achieve this objective. Over-circulation leads to increased methane emissions. Operators can adjust this circulation rate at no additional cost and decrease methane emissions from the dehydrator system.

Another way to decrease methane emissions from TEG systems is to install flash tank separators. Flash tank separators capture approximately 90 percent of the methane entrained in the TEG, preventing the methane from being boiled off into the atmosphere when the TEG passes through the regenerator.

Desiccant dehydrators can be good alternatives to TEG systems under certain circumstances. They work best when the volume of gas processed per day is high (at least 28,000 Mcm/day), the temperature is low ($<21^{o}$ C), and the gas pressure is high (>6.8 atmospheres). With no regenerator, desiccant dehydrators produce methane emissions only when they are being refilled with desiccant, and even then the volumes are far below those from TEG systems.

3.3 PLUNGER LIFTS

Fluid accumulation in gas wells can impede or halt gas production. Traditional techniques for removing the fluid include use of a beam pump, remedial treatments, or venting the well to the atmosphere, all of which result in methane release to the atmosphere. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the well to push a steel plunger, and the column of fluid ahead of it, up the well tubing to the surface. Instead of being vented to the atmosphere, gas is captured and routed to the sales line. A plunger lift can be a cost-effective alternative to beam lifts and well blowdown, reduces methane emissions, and increases the productivity of the gas well.

One gas company, after installing plunger lifts in an entire production field, realized an annual per well gas savings of 319 Mcm, worth US$33,822 at US$105 per Mcm. Plunger lift installation costs per well were approximately US$10,000, meaning that the investment was recovered in about three months. Additional savings in chemical treatment, electrical, and workover costs made the economics of plunger lift installation even more attractive.

3.4 VAPOR RECOVERY UNITS

During storage of crude oil, methane and other gases vaporize and collect in the space between the liquid and the fixed roof of the tank. As the liquid level in the tank fluctuates, these vapors are often vented to the atmosphere. One way production sector companies can prevent these emissions is to install vapor recovery units (VRUs) on oil storage tanks. A VRU draws over 95 percent of the hydrocarbon vapors out of a storage tank or set of tanks under low pressure. The vapors are then routed to a scrubber and then used as an on-site fuel supply or sold.

One natural gas production company installed eight VRUs on crude oil storage tanks, realizing 620 Mcm (or US$65,700 at US$105 per Mcm) in gas savings per unit. Capital and installation costs were estimated to be US$30,000 per unit, meaning that the project realized a payback in less than one year.

3.5 ROD PACKING

In the transmission sector, packing systems are used to maintain a tight seal around the compressor piston rod, preventing the pressurized gas from leaking. Even under the best conditions, new packing systems properly installed will still leak a minimum of 0.32 cubic meters of gas per hour (scmh). With time, leak rates increase from wear on the packing rings and the piston rod. One natural gas company reported measuring emissions of 25.5 scmh on one compressor rod. Replacement of rod packing is commonly done at a set interval (for example, every four years), without regard to leakage rate.

By comparing the initial loss rate with the current loss rate, it is possible to calculate an 'economic replacement threshold', or in other words, the time period in which the value of the gas justifies replacement of the packing rings. A side benefit of early replacement of packing rings is the extension of the life of the piston rod.

One company replaced worn compressor rod packing rings on 15 compressor units and saved 198 Mcm per year, worth US$21,000 at US$105 per Mcm. The total cost of replacing all the rings, including materials and labor, was US$17,000, resulting in a payback period of less than one year.

3.6 REPLACING WET COMPRESSOR SEALS

Centrifugal compressors, which are common in the production and transmission sectors of the natural gas industry, employ seals on the rotating shaft to prevent the high pressure gas from escaping the compressor casing. These seals commonly use high pressure oil to form a barrier against the compressed gas. Although these wet seals, when operating properly, are effective at preventing gas losses from the compressor shaft area, they lead to gas emissions when the circulating oil undergoes degassing, typically from 1 to 6 standard cubic meters per minute (scmm).

At low to moderate pressures (up to 200 atmospheres) and temperatures below 150^{o} C, dry seals can be much more effective at preventing gas leakage from around the shaft (often less than 0.2 scmm), and do not require the elaborate circulation and degassing systems of a wet seal system. A dry seal can save about US$135,000 per year and pay for itself in as little as 14 months. Replacement of wet seals with dry seals also leads to substantially reduced operating and maintenance expenses, improved reliability, and reduced contamination of the gas.

3.7 COMPOSITE WRAP

In all sectors of the industry, the traditional method for rehabilitating a pipe with a non-leaking defect is to shut off flow to the segment of pipe, vent the pipe to the atmosphere, cut out the damaged pipe, and weld in a new pipe segment. Recently many gas companies have started employing another practice: wrapping a composite sleeve around the existing pipe. For many defects, this technique is easier than cut-and-weld, less expensive, and avoids the need to purge the pipeline to the atmosphere.

One gas company has completed more than 300 composite wrap repairs on transmission lines since 1995. This company as stated that cost is often a secondary consideration in selecting this technology over pipeline replacement. The main benefits, they claim, are uninterrupted service during repairs, speed of repair, and reduction of safety concerns.

3.8 PIPELINE PUMPDOWN

As stated above, pipeline repairs and maintenance activities typically require removal of gas from the affected section of pipe to ensure safe working conditions. Another way to minimize the amount of gas emitted to the atmosphere, besides using composite wraps, is to use pumpdown techniques to lower the gas line pressure before venting. This can be done in one of two ways: either with in-line compressors (which can draw down pressure by approximately 50 percent), or with a combination of in-line and portable compressors (which can together achieve up to 90 percent pressure reduction).

One company saved 922 Mcm in one year by using pump-down compressors to evacuate pipelines. The company used compressors at one location three times during the year at a total cost of US$52,600. Since the gas saved was worth US$93,200 at US$105 per Mcm, the cost of the portable compressors was easily justified.

3.9 DIRECTED INSPECTION AND MAINTENANCE

Aboveground gas system facilities contain a number of components which potentially leak gas, including flanged joints, other mechanical joint and connections, valves, pressure relief valves, open ended lines (OELs), and seals in pumps and compressors. Directed inspection and maintenance (DI&M) programs are designed to identify the source of these leaks, and prioritize and plan their repair in a timely fashion. A reliable and effective DI&M plan for an individual facility will be comprised of a number of components, including a method or methods of leak detection, a definition of what constitutes a leak, set schedules and targeted devices for leak surveys, and allowable repair time.

A DI&M program begins with a baseline survey to identify and quantify leaks. Quantification of the leaks is critical because this information is used to determine which leaks are serious enough to justify their repair costs. Repairs are then made only to the leaking components that are cost effective to fix. Subsequent surveys are then scheduled and designed based on information collected from previous surveys, permitting operators to concentrate on the components that are more likely to leak. Some natural gas companies have demonstrated that DI&M programs can profitably eliminate as much as 95 percent of gas losses from equipment leaks.

3.9.1 DI&M AT GAS PROCESSING FACILITIES

Studies have shown that five categories of equipment components at gas processing facilities contribute the majority of methane losses: block valves, control valves, connectors, compressor seals and OELs. Once leaks are identified via screening techniques, accurate leak measurements are obtained using bagging techniques, a high volume sampler or a toxic vapor analyzer (TVA) with site specific concentration correlations. Gas savings from implementing this practice will vary depending on the size and age of the facility, the number and types of components included in the DI&M program, and the operating characteristics of the facility, but many processing companies have found that the initial expense of a baseline survey is quickly recovered in gas savings.

One study found that emissions from the four gas processing plants surveyed averaged 2,308 Mcm per year. Properly conducted DI&M programs have shown to result in reductions of methane emissions by 70%. This translates to saving 1,615 Mcm per year per facility, or over US$170,000 a year at US$105 per Mcm.

3.9.2 DI&M AT COMPRESSOR STATIONS

Data collected from natural gas companies shows that 95 percent of methane emissions at compressor stations are from 20 percent of the leaky components. The purpose of directed inspection and maintenance programs at compressor stations is to enable the facility operators to concentrate resources on finding and fixing these major leaks. One study reported on the results of emissions studies at 13 compressor stations with varying numbers of reciprocating and centrifugal compressors. Although only 5 percent of the components at these sites were found to be leaking, the total leak rates ranged from 11 Mcm per year to 5,664 Mcm per year. The biggest sources of individual leaks were packing seals, blowdown valves, OELs and pneumatic vents. The study went on to find that, for most of the sites, the initial expense of the baseline survey and repair costs were quickly recovered in gas savings.

One company reported surveying two compressor stations quarterly. Survey costs averaged US$200 per station, and leak repairs averaged US$50 per leak. Gas savings totaled 484 Mcm, or 242 Mcm per station. The ratio of savings to costs for this company was calculated to be 19 to 1.

3.9.3 DI&M AT GATE STATIONS AND SURFACE FACILITIES

Gate stations and surface facilities in the distribution sector vary significantly in size and pressure capacity, and as a result there can be substantial variation in fugitive methane emissions from these facilities. According to two studies, the average total emissions that a DI&M program would address amounts to approximately 0.6 - 1.2 Mcm per site. Because this amount is so low compared to processing plants (1,615 Mcm/facility) and compressor stations (11 - 5,664 Mcm/facility), companies planning to conduct a DI&M program at their gate stations and surface facilities must rely on low cost and rapid screening techniques (such as applying soapy water to a potential leak location and looking for bubble formation) so that the cost of finding and fixing the leaks does not outweigh the savings gained from fixing the leaks.

One company surveyed 86 facilities one year, finding leaks at 48 sites. The total cost to find and fix the leaks was US$2,453, while total gas savings was 43 Mcm (or US$4,557 at US$105 per Mcm) per year. Net savings were approximately US$24 per facility.

4.0 CONCLUSIONS

There are numerous ways natural gas companies can reduce their methane emissions, and many of these technologies and practices cost less to implement than the value of the gas they save. Often payback is achieved in a matter of a few months. Although this paper discusses technologies and practices prevalent in the United States, all activities are feasible anywhere in the world.

For more information about any of these technologies or practices, please visit the USEPA Natural Gas STAR website at www.epa.gov/gasstar

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